

**BEFORE THE PUBLIC SERVICE COMMISSION
OF UTAH**

IN THE MATTER OF:

Joint Application of Questar Gas)
Company, the Division of Public)
Utilities, and Utah Clean Energy) **Docket Number 05-057-T01**
For the Approval of the Conservation)
Enabling Tariff Adjustment Option)
And Accounting Orders)

**DIRECT TESTIMONY
OF
DAVID E. DISMUKES, PH.D.**

**ON BEHALF OF THE
UTAH COMMITTEE OF CONSUMER SERVICES**

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DOCKET NO. 05-057-T01

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 6455 Overton Street, Baton Rouge, Louisiana.

Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am a Consulting Economist with the Acadian Consulting Group (“ACG”), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana with additional staff in Los Angeles, California, and Carson City, Nevada.

Q. HAVE YOU PREPARED ANY ATTACHMENTS TO YOUR TESTIMONY OUTLINING YOUR QUALIFICATIONS IN ENERGY AND REGULATED INDUSTRIES?

A. Yes. Attachment 1 to my testimony provides my professional resume that

includes a complete list of my publications, presentations, and pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by Utah Committee of Consumer Services (“Committee”) to provide an expert opinion on whether or not Questar Gas Company’s (“Questar” or “the Company”) Conservation Enabling Tariff (“CET”) should be continued.

Q. HOW IS THE REMAINDER OF YOUR CURRENT TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations;
- Section III: Procedural History;
- Section IV: Overview of Revenue Neutrality Mechanisms;
- Section V: Maintaining the CET Would Not Be in the Public Interest and Should be Discontinued;
- Section VI: Direct Ratepayer Benefits of the CET are Small
- Section VII: Alternative Remedies for Dealing with Energy Efficiency Disincentives;
- Section VIII: Alternative Methods for Dealing with Declining Use Per Customer;
- Section IX: Conclusions and Recommendations.

Q. HAVE YOU PROVIDED ANY ATTACHMENTS TO YOUR TESTIMONY?

46 A. Yes, I have included two attachments to my testimony which include my
47 professional resume and a summary overview of state decisions where revenue
48 decoupling was rejected or withdrawn. .

49 **Q. HAVE YOU PROVIDED ANY EXHIBITS TO YOUR TESTIMONY?**

50 A. Yes, I have prepared 17 exhibits to accompany my testimony. The
51 exhibits were prepared by me or under my direct supervision.

52 **II. SUMMARY OF RECOMMENDATIONS**

53 **Q. WHAT IS YOUR GENERAL RECOMMENDATION IN THIS**
54 **PROCEEDING?**

55 A. The CET should be discontinued on a forward going basis. In examining
56 the Company's potential revenues at risk, it is clear at this time that the most
57 significant challenge it faces is a potential exposure to future revenue losses
58 resulting from declines in use per customer rather than large revenue losses
59 associated with the promotion of Demand-Side Management ("DSM") programs.
60 Revenue losses resulting from DSM programs are estimated to be less than one-
61 half of one percent; thus, they are simply not that significant and can be easily
62 accommodated within a straightforward lost revenues adjustment mechanism.

63 **Q. HOW CAN A DECLINE IN USE PER CUSTOMER CREATE RISKS FOR**
64 **A COMPANY THAT IS SEEING STRONG REVENUE GROWTH RIGHT NOW?**

65 A. Revenue changes, as I will discuss later in my testimony, have two related
66 parts that involve both (1) changes in use per customer and (2) changes in the
67 number of customers. Currently, revenues are increasing due to rapid customer
68 growth. The Company's problem appears to stem from the relationship between

the marginal increase in revenues associated with new customers and a much higher marginal increase in investment cost per customer.

Q. SHOULDN'T THE COMPANY BE GIVEN AN OPPORTUNITY TO EARN ITS ALLOWED RETURN?

A. Yes, but it is my recommendation that the CET is not the appropriate mechanism to use for maintaining this opportunity. As I discuss in my testimony, there are a wide range of other regulatory mechanisms that can address these ratemaking and cost-recovery problems.

Q. HAS THE COMPANY'S EARNINGS SUFFERED DUE TO THESE CHANGES IN USE PER CUSTOMER?

A. No. The Company's earnings have not suffered primarily because revenues from overall customer growth have been so significant. Over the past five years, the Company's Utah jurisdictional DNG related return on equity (ROE) has been between 9.06 and 11.09 percent. In 2006, the Company's earnings were 10.86 percent compared to its currently allowed return of 11.2 percent. Earnings for 2007 are forecasted to be 10.32 percent.

Q. WHAT ARE YOUR FUNDAMENTAL OBJECTIONS TO THE USE OF REVENUE DECOUPLING MECHANISMS LIKE THE CET?

A. Revenue decoupling mechanisms are overly broad and shift considerable usage-related risks from the Company and its shareholders to ratepayers. Mechanisms like the CET eliminate a customer's ability to fully realize the complete benefits of their actions to reduce consumption in this high energy price

environment. This is neither fair nor efficient since over the long run it can dampen customers' incentives to reduce consumption.

Q. DO YOU SEE DECOUPLING AS PART OF A BROADER TREND IN UTILITY REGULATORY PROPOSALS?

A. Yes. As I will discuss later in my testimony, revenue decoupling is part of a broader set of policy initiatives offered by utilities which shift risk from shareholders to ratepayers. Some of these proposals in gas industry regulation include:

- (1) The creation of gas cost recovery ("GCR") mechanisms;
- (2) The creation of weather normalization clauses;
- (3) The recovery of Lost and Unaccounted for Gas ("LAUF") in GCRs;
- (4) The creation of pipeline replacement cost recovery riders;
- (5) Shorter weather normalization periods.

Some of the recent proposals in electric industry regulation include:

- (1) Bonus or incentive ROEs on the construction of baseload power plants;
- (2) Cash earnings on Construction Work in Progress ("CWIP") on nuclear power plants and other baseload generation investments;
- (3) Cash earnings on CWIP for power transmission investments;
- (4) Antecedent prudence reviews on major capital projects;
- (5) Shorter weather normalization periods.

Q. DO YOU HAVE ANY CONCERNS ABOUT THESE TYPES OF PROPOSALS?

A. Yes, these types of proposals raise questions about the proper risk sharing relationship between ratepayers and shareholders. In reviewing several of these types of proposals in both the gas and electric industry, my concern is (1) the precedent-setting nature of the decisions, (2) their piecemeal adoption, and (3) the potential movement down a slippery slope of disjointed policy mechanisms that have interactive and unintended rate implications for ratepayers. One particular concern I have is that many of these proposals fail to attempt to make any ratemaking adjustment for this fundamental shift in risk from shareholders to ratepayers..

Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS IN THIS PROCEEDING?

A. I have three primary recommendations:

(1) The Commission should discontinue the use of the CET since it shifts considerable sales risk to ratepayers with little to no offsetting benefits for ratepayers assuming those risks. Further, the CET is overly broad in addressing the problems associated with declining use per customer trends and is unnecessary to address incentive issues associated with the promotion of DSM programs.

(2) The Commission should adopt a lost revenue adjustment ("LRA") mechanism to make the Company whole for changes in usage resulting from its DSM programs. Lost revenue recovery should be tied directly to the estimates included in the Company's DSM cost-effectiveness filings, and updated according to the ongoing

137 monitoring and verification (M&V) process.

138 (3) The Commission should direct the Company to address any
139 financial challenges created by decreases in use per customer in its
140 next rate case through the use of a forecasted test year or some
141 known and measurable adjustment if a historic test year is utilized
142 for ratemaking purposes.

143 **Q. DO YOU HAVE ALTERNATIVE RECOMMENDATIONS?**

144 A. Yes, should the Commission reject my primary recommendations and
145 decide to maintain the CET I would recommend:

146 (1) The Commission require the CET to be modified such that
147 decoupling true-ups are based upon the difference in historic and
148 actual use per customer times test year customers (or base year
149 customers upon which the revenue per customer statistic is
150 derived) rather than actual customers.

151 (2) The Commission should explicitly recognize the risk shifting nature
152 of the CET and indicate in its Order that this shifting of risk will be
153 considered in setting the Company's ROE in its next rate case.

154 **III. PROCEDURAL HISTORY**

155 **Q. WOULD YOU PLEASE DISCUSS YOUR UNDERSTANDING OF THIS**
156 **PROCEEDING'S ORIGINS?**

157 A. On December 16, 2005, the Company, the Division of Public Utilities ("the
158 Division") and Utah Clean Energy ("UCE") filed a Joint Application requesting
159 approval of a Conservation Enabling Tariff ("CET") and other enabling accounting

mechanisms and proposals. The Joint Applicants offered the CET proposal to remedy what they saw as two fundamental problems confronting the Company. The first problem was the purported financial disincentive related to the promotion of DSM programs. The second problem was the claimed financial challenges stemming from a declining use per customer trend.

**Q. WERE YOU ASKED BY THE COMMITTEE TO OFFER AN EXPERT
OPINION ON THE CET PROPOSAL?**

A. Yes. I provided rebuttal testimony to the Joint Applicants on May 15, 2006. It was my expert opinion and recommendation that the Commission reject the CET proposal as not being in the public interest. My testimony stated:

(1) The CET represented a significant change in ratemaking and shifted risk to customers without any corresponding offset or benefit like a reduction on the overall allowed rate of return. It was, and still is my opinion, that the benefits of the CET are clear for Questar, but questionable for ratepayers.

(2) The CET proposal, as a mechanism to support DSM and declining use per customer trend, was based upon a questionable premise of disincentives. For instance:

a. Utilities have an obligation to provide least-cost reliable service, and if DSM is the least cost resource, utilities are obligated to acquire that resource.

b. If utilities experience a decline in earnings from declining use per customer, they have the option of seeking rate relief.

(3) There are a number of other, less dramatic regulatory mechanisms that can adjust utility rates for changes in usage created by either long run trends in overall efficiency or the Company's DSM programs.

Q. HAS YOUR EXPERT OPINION CHANGED SINCE FILING YOUR TESTIMONY LAST YEAR?

A. No. My expert opinion has not changed. I continue to believe that the CET is not a positive rate design change for ratepayers. I recommend that the Commission discontinue its use on a forward-going basis.

Q. DID YOU OFFER ANY ADJUSTMENTS OR ALTERNATIVES TO THE CET AS A RESULT OF THE JUNE 7, 2006 TECHNICAL CONFERENCE?

A. The Commission's Staff requested that parties provide a number of potential alternatives to the proposed CET during the course of the June 7, 2006 Technical Conference. This request was part of a larger set of questions submitted by Commission Staff to parties for comment relative to the CET. I provided Supplemental Testimony responding to all of these questions, including a number of possible alternatives to the CET. The two alternatives that I provided at that time were: (1) an incentive-based system where a utility's reward increases as it secures greater levels of cost-effective DSM savings; and (2) a "statistical recoupling" mechanism that would attempt to re-couple some of the exogenous factors (changes in gas commodity prices, economy, weather, etc.) impacting revenue back onto the Company and its shareholders.

IV. OVERVIEW OF REVENUE NEUTRALITY MECHANISMS

Q. WOULD YOU PLEASE DEFINE REVENUE NEUTRALITY?

206 A. Revenue neutrality can be defined as a set of policy mechanisms that
207 make a utility indifferent to its level of sales. Typically, these policy mechanisms
208 establish rate designs that either (a) remove revenue recovery from sales
209 through some kind of fixed charge or (b) true-up revenues to some target
210 amount. The goal of revenue neutrality mechanisms has generally been to
211 remove a utility's purported disincentive to promoting energy efficiency. Over
212 time, revenue neutrality mechanisms began to be promoted as (a) more
213 consistent with "sound economic principles," and (b) giving utilities a better
214 opportunity to earn their authorized rates of return.

215 **Q. IS REVENUE NEUTRALITY A NEW IDEA?**

216 A. No. As a regulatory concept, revenue neutrality has been around for
217 nearly twenty years. In fact, the first Energy Policy Act (of 1992) addressed
218 revenue neutrality and required states to consider this mechanism in conjunction
219 with integrated resource planning ("IRP") standards, which emphasized the use
220 of demand-side resources in a manner comparable to traditional supply-side
221 considerations. The purported goals of revenue neutrality policies then, as well
222 as now, were to develop rate design approaches that supposedly make a utility
223 indifferent between promoting energy efficiency and sales.

224 **Q. WHAT TYPES OF POLICY MECHANISMS ARE USED TO PROMOTE**
225 **REVENUE NEUTRALITY?**

226 A. Since the early 1990s, a variety of different approaches to revenue
227 neutrality have been adopted. The primary revenue neutrality methods being
228 promoted in the natural gas industry include what are commonly referred to as

229 “revenue decoupling” (and its different forms) and “straight-fixed variable” (“SFV”)
230 rate design mechanisms.

231 **Q. HAS REVENUE NEUTRALITY BEEN WIDELY ADOPTED SINCE THE**
232 **PASSAGE OF EPACT 1992?**

233 A. No. The original impetus for revenue neutrality was in the electric power
234 industry. However, a combination of competition, a decades-long boom in the
235 U.S. economy, and low fossil fuel prices worked to diminish interest in revenue
236 decoupling throughout most of the 1990s. Recent increases in fossil fuel prices,
237 particularly natural gas, have renewed interest in this ratemaking concept,
238 particularly for natural gas LDCs, although several electric utilities are starting to
239 revisit the concept as well.

240 **Q. CAN YOU BRIEFLY DESCRIBE A SFV RATE DESIGN?**

241 A. A SFV rate design represents a dramatic change in the method in which
242 utilities charge their customers for distribution service. Common utility pricing
243 practice is based upon what is referred to as a “two-part tariff.” This two-part
244 tariff is comprised of a fixed customer charge and a per unit (volumetric) charge.
245 Natural gas commodity charges are also variable, and applied to customers’ bills
246 on a usage basis. A SFV rate design completely changes this pricing practice
247 and recovers all distribution (non-gas) charges on a fixed basis rather than the
248 commonly accepted two-part approach. Under SFV, the only variable charge the
249 customer will see is the commodity gas charges recovered through the gas cost
250 recovery (“GCR”) rate.

Q. EARLIER YOU MENTIONED THAT REVENUE DECOUPLING IS A FORM OF REVENUE NEUTRALITY. PLEASE EXPLAIN THE CONCEPT OF REVENUE DECOUPLING IN GREATER DETAIL?

A. Revenue decoupling is a form of revenue neutrality that changes the manner in which revenues are collected from ratepayers. Typically, rates are fixed and based upon an allowed rate of return (among other factors). While the allowed revenues included in this formula are considered fixed, actual revenues vary from year-to-year depending upon a wide range of factors. Revenue decoupling basically changes the nature of this process. Under a revenue decoupling regime, revenues are fixed and virtually guaranteed while rates are allowed to vary from year-to-year to assure a guaranteed level of revenue recovery.

Q. HOW DOES REVENUE DECOUPLING WORK?

A. Revenue decoupling is typically done on a revenue per customer basis where an allowed revenue per customer is established in a rate case, or some other agreed upon level. This allowed revenue per customer is then determined for every month of the year. Over time, the allowed revenue per customer is compared to the actual revenue per customer. If actual revenues are lower than allowed, the revenue shortfall is booked to a true-up account to be factored into rates. These true-ups can occur as frequently as every month, every quarter, or annually. The process is symmetrical – if revenues are greater than allowed, excess revenues are credited to the balancing account for a future rate decrease.

Q. CAN REVENUE DECOUPLING TAKE DIFFERENT FORMS?

274 A. Yes, there are two general forms of revenue decoupling: full revenue
275 decoupling and partial revenue decoupling. Full decoupling allows the entire
276 under or over-recovery of revenues to fall into a balancing account for later true
277 up. Partial decoupling only allows some part of that overage/underage to enter
278 the balancing account. In some instances, the balances are adjusted for
279 changes in prices, weather, and/or the economy. That is, revenue changes
280 related to gas commodity prices, the economy or weather are not eligible for
281 recovery in the balancing account. This process can also be referred to as
282 “statistical re-coupling” since estimates from statistical load forecasts are used to
283 make the price, weather, and economic-related adjustments. Another form of
284 partial decoupling can occur through a fixed cap percentage on revenue
285 recovery. For instance, North Carolina has caps on total decoupling balance
286 recoveries. The current interim approach in Utah also has a cap on total
287 revenues that can be recovered in the decoupling balancing account.

288 **Q. ARE SFV AND REVENUE DECOUPLING RELATED?**

289 A. Somewhat. Revenue decoupling usually preserves the traditional rate
290 design structure utilized by most state regulatory commissions where distribution
291 service rates are comprised of a fixed customer charge and a volumetric
292 distribution charge. Revenue decoupling sets a revenue per customer level to be
293 recovered under these rates: if actual recovery falls below the target, then rates
294 are increased in a subsequent period to make up for the shortfall and vice versa.
295 Thus, one can think of revenue decoupling as creating a true-up process that
296 sets variable rates at a level that makes customers indifferent between rates

being fixed or variable. SFV can be thought of as “perfect revenue decoupling” since rates are not required to be “trued-up” in any given year and are directly (rather than indirectly) charged to customers on a fixed per-customer basis.

Q. HOW ARE THESE TWO REVENUE NEUTRALITY MECHANISMS RELATED TO QUESTAR’S CET?

A. The Company’s CET is a form of full revenue decoupling where actual revenues are trued-up to some fixed benchmark. Customers would still be billed on a volumetric basis, but these volumetric rates would be “trued-up” periodically based upon the actual revenues collected per customer. In effect, the revenue decoupling process makes the Company indifferent between collecting DNG revenues through fixed or variable charges. The process is similar in many ways to loading total DNG revenue requirements into a fixed charge since customers are no longer able to avoid any portion of the DNG revenue requirement through reduced usage.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes, CCS Exhibit 1.1 shows how the CET works. The first step, conducted in an earlier phase of this proceeding, was to set a base year (or test year) DNG revenue per customer level. For illustration purposes, the test year total DNG revenue per customer is \$250. The second step is to allocate the total charge per customer on a monthly basis over the course of a “typical” year which is provided in the second box of this exhibit. Each month the actual revenues collected per customer (from the per unit, or per Mcf charge) are compared to allowed monthly amounts and are either credited or debited to a balancing

account. The balancing account is “trued-up” at every six months, and the resulting amount is applied to the volumetric charge on customers’ bills. The new volumetric charge resulting from the example is provided in the third box. This represents the difference for the month of January alone. The same procedure would need to be replicated for the remaining 11 months of the year, and the accrual summed to a total amount.

Q. IS REVENUE NEUTRALITY PRESENTLY UNDERGOING AN ACTIVE POLICY DEBATE?

A. Yes. Revenue neutrality is being actively debated before various state legislatures and state regulatory commissions. For some groups, revenue neutrality is seen as a must-have for the promotion of energy efficiency. Other groups, particularly consumer groups, are very concerned about the adoption of these types of policy mechanisms and the implications they may have for customer bills. Two prominent consumer groups have recently either opposed or had members expressing serious concerns regarding revenue neutrality mechanisms. These groups include the Electric Consumers Resource Council (“ELCON”) and the National Association of State Utility Consumer Advocates (“NASUCA”).

Q. WHAT POSITION HAS ELCON TAKEN RECENTLY ON REVENUE DECOUPLING?

A. ELCON, an advocacy group comprised of a large number of major industrial customers of electricity, has recently issued both a position statement and White Paper that is adamantly opposed to revenue decoupling: a position

similar to that taken by most industrial customers in the early 1990s when revenue neutrality mechanisms were initially debated. The White Paper issued by ELCON noted many flaws with this policy mechanism including:

- (1) Decoupling promotes mediocrity in the management of a utility;
- (2) Decoupling shifts significant business risk from shareholders to consumers with only limited opportunities for net increases in consumer benefits;
- (3) Decoupling eliminates a utility's financial incentive to support economic development within its franchise area;
- (4) Decoupling tends to address "Lost Revenues" and not the real issue which is "lost profits;"
- (5) Sending appropriate price signals is the most important step in promoting energy efficiency;
- (6) Third party, independent delivery of energy efficiency services is a more effective means of addressing incentives.

Q. WHO DOES NASUCA REPRESENT?

A. NASUCA represents the various state-funded attorneys general, consumer counsels, and consumer advocate agencies charged with representing the interests of small customers in utility proceedings.

Q. HAS NASUCA ISSUED A FORMAL POSITION STATEMENT OR RESOLUTION ON REVENUE DECOUPLING?

A. Decoupling is a topic being closely watched by various NASUCA Committees (consumer protection, gas and electric) and will be actively

discussed in Denver this summer. Most of the member states of NASUCA that have been engaged in revenue neutrality proceedings at the state level have opposed most forms of revenue neutrality, including revenue decoupling.

Q. WHAT IS THE CURRENT STATUS OF REVENUE NEUTRALITY PROPOSALS?

A. Various states have taken action on revenue decoupling and SFV rate design proposals for both electric and gas utilities. CCS Exhibit 1.2 and CCS Exhibit 1.3 provide maps showing the states that have considered each of these policy mechanisms. While many states have considered both forms of revenue neutrality, very few have adopted SFV, while only slightly more have embraced revenue decoupling.

Q. HOW MANY STATES HAVE EITHER ADOPTED OR ARE CURRENTLY CONSIDERING THE ADOPTION OF REVENUE DECOUPLING MECHANISMS?

A. CCS Exhibit 1.2 shows the recent activity on revenue decoupling for electric and gas utilities across the U.S. Currently, there are ten states that have adopted revenue decoupling as either a permanent or pilot mechanism for electric and/or gas utilities. These states include North Carolina, Indiana, Ohio, New Jersey, Maryland, Vermont, California, Oregon, Idaho, and Utah. Another three states (Minnesota, Colorado, and Nebraska) are currently considering revenue decoupling.

Q. HAVE ANY STATES REJECTED REVENUE DECOUPLING PROPOSALS?

389 A. Yes, revenue decoupling proposals for gas or electric utilities have either
390 been rejected by state commissions or withdrawn by utilities in eleven states,
391 including Washington, Arizona, Nevada, Kansas, Arkansas, Wisconsin, New
392 York, Delaware, Michigan, Iowa, and Connecticut. All of these states except for
393 Arkansas have an active DSM program in place for the utility whose revenue
394 decoupling proposal was either rejected or withdrawn. Most state commissions
395 rejected revenue decoupling on a variety of sound public policy reasons that are
396 consistent with the position taken by the Committee in this proceeding. Further,
397 many of these state commissions were not convinced that revenue decoupling
398 was necessary for the adoption of cost-effective DSM programs. Appendix 2
399 provides a summary of the state decisions rejecting revenue decoupling or states
400 in which revenue decoupling proposals were withdrawn.

401 **Q. IS REVENUE DECOUPLING REQUIRED FOR THE ADOPTION OF**
402 **ENERGY EFFICIENCY?**

403 A. No. CCS Exhibit 1.2 clearly shows there are a large number of electric
404 and gas utilities operating in ten states that have mature and extensive energy
405 efficiency programs without a revenue decoupling mechanism. Some 21 states,
406 accounting for around 47 percent of all U.S. residential electric and gas
407 customers, have found a way to promote energy efficiency under more traditional
408 ratemaking approaches.

409 **Q. HAVE THE STATES RECENTLY ADOPTING REVENUE DECOUPLING**
410 **SEEN CONSIDERABLE DSM INITIATIVES BY THEIR REGULATED**
411 **UTILITIES?**

A. Some have, while others have not. In Utah, Questar has clearly made a significant effort in developing DSM programs on an accelerated pace. However, in other states, the results are a little more mixed. For example, revenue decoupling was adopted in Ohio and Indiana in the latter half of 2006, but utilities have been slow to respond with new DSM programs. North Carolina adopted revenue decoupling about 18 months ago and ratepayers are being asked to cover a \$50 million revenue decoupling balancing account shortfall with what appears to be limited access to DSM programs.

Q. WHAT HAS BEEN THE PROCEDURAL CONTEXT IN WHICH REVENUE NEUTRALITY PROPOSALS HAVE BEEN CONSIDERED IN OTHER STATES?

A. Over the past three years, revenue neutrality programs have been considered in at least 15 rate case proceedings rather than a stand-alone docket like the one in Utah. This is an important distinction since a rate case gives a regulatory commission, as well as other parties, a wide range of ratemaking tools and policy options to address structural and programmatic changes in demand that may be affecting a utility's earnings.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW A RATE CASE WOULD BE A BETTER VENUE TO CONSIDER MANY OF THE ISSUES RAISED BY THE COMPANY?

A. Yes, if the declining use per customer trend is significant and quantifiable, then there are approaches such as repression adjustments to test year billing determinants that can account for the structural changes in demand. Examining

these issues outside of a general rate case confines the potential remedies to an “all-or-nothing” solution: revenue decoupling or nothing. Unfortunately, this is very limiting, and I will discuss some of the other options at the Commission’s disposal (most of which would be in the context of a rate case) in Section VII of my testimony.

V. MAINTAINING THE CET WOULD NOT BE IN THE PUBLIC INTEREST AND SHOULD BE DISCONTINUED

Q. IS IT CLEAR THAT A SIGNIFICANT UTILITY DISINCENTIVE TO PROMOTE ENERGY EFFICIENCY REALLY EXISTS?

A. No. It is not clear that a significant utility disincentive exists in promoting least-cost efficiency resources because often the net results of utility-sponsored DSM are varied. For some utilities, promoting energy efficiency can be a means of offering a value-added service that reduces customer bills, increases customer satisfaction, increases planning flexibility, and reduces the overall long run cost of service. Further, utilities should have a very strong incentive to develop least cost resources through traditional regulation and their opportunity to earn a fair rate of return on their investments.

Q. ARE THERE ANY OTHER REASONS WHY DSM CAN IMPACT UTILITY PROFITABILITY DIFFERENTLY?

A. Yes, it is difficult to assign any generalized DSM-specific impact on utility profitability since the net result is influenced by a range of factors that can include the types of programs a utility promotes, the forecasted changes in its customer base and its costs of serving those customers, the certainty with which it has

estimated potential customer savings, the costs and scope of the energy efficiency programs it is promoting, and other incentives (both positive and negative) that have been offered by its state utility regulators.

Q. IN LOOKING AT OTHER GAS UTILITIES, IS IT THE CASE THAT REVENUE DECOUPLING IS NEEDED IN ORDER TO BE SUCCESSFUL AT PROMOTING DSM?

A. No, that does not appear to be the case. CCS Exhibit 1.4 is a modified version of an exhibit presented by one of the Joint Applicants in the original filing (Exhibit HG-2) examining DSM programs, costs, and savings for 2004. Of the ten gas utilities listed, only three have revenue decoupling. Interestingly enough, the top two gas utilities on the list in terms of total program spending as a percent of retail revenues (Vermont Gas and Aquila) do not have revenue decoupling. However, these two utilities outspend as a share of revenues, the three utilities that have revenue decoupling. In terms of performance, Vermont Gas and Keyspan were able to attain benefit-cost ratios of 5.6 and 3.0, respectively, without any type of revenue decoupling program.

Q. LOOKING AT THIS ISSUE MORE BROADLY, IS IT THE CASE THAT MOST ELECTRIC AND GAS UTILITIES PROMOTING DSM HAVE REVENUE DECOUPLING MECHANISMS?

A. No. Exhibit CCS Exhibit 1.2, discussed earlier, also shows that there are several states that require the use of energy efficiency programs yet have no revenue decoupling mechanisms. Currently, there are ten states that have energy efficiency programs but do not have revenue decoupling mechanisms.

Further, all of the 11 states which recently rejected or withdrew revenue decoupling have programs to support energy efficiency. In total, there are some 21 states which support energy efficiency without revenue decoupling.

Q. DOES REVENUE DECOUPLING HAVE ANY NEGATIVE IMPLICATIONS FOR RATEPAYERS?

A. Yes, revenue neutrality proposals can have a number of negative implications for ratepayers including shifting a wide range of traditional business risks away from shareholders and towards ratepayers. This includes risks associated with changes in the economy, changes in commodity prices, and in some instances, changes in weather. Those proposals that fail to account for this risk shifting, through some type of adjustment mechanism, can impose a cost onto ratepayers without any corresponding benefit.

Q. HOW DO TYPICAL REVENUE NEUTRALITY PROPOSALS SHIFT RISK AWAY FROM UTILITIES AND TOWARDS CUSTOMERS?

A. Risk is shifted to customers through the revenue per customer true-up mechanism. This mechanism provides utilities with a **guaranteed** revenue per customer amount. Current regulatory approaches only give utilities an **opportunity** to earn typical revenues, but do not guarantee that recovery. Under the current rate design, customers have the opportunity to avoid a portion of their distribution non-gas charges if they conserve energy (lower consumption), install energy efficient appliances, or take other energy efficiency steps. This will not be the case under the CET which essentially requires customers to reimburse the utility for any savings that result from customers' conservation efforts. .

**Q. WHAT TYPES OF FACTORS IMPACT REVENUE RECOVERY UNDER
TRADITIONAL REGULATORY APPROACHES?**

A. A number of factors can influence sales including economic conditions, gas commodity prices, weather, and other unanticipated events that impact usage. Under traditional regulation, these risks are usually borne by the utility, not by ratepayers. Under the Company's proposals, these risks are entirely shifted to ratepayers since there is no means for customers to reduce distribution charges by reducing usage in the face of economic recessions, higher prices, warmer weather, and other factors.

Q. HOW ARE ECONOMIC RISKS SHIFTED TO RATEPAYERS?

A. If revenues decline due to a contraction in the economy, customers will be required to make the utility whole for those revenue shortfalls. Decreases in sales associated with economic downturns have nothing to do with energy efficiency or a DSM program promoted by the Company. Instead, they are the natural reaction of households trying to reduce their expenditures during difficult economic times. Under the CET, customers will be required to make a utility whole for possible losses during economic downturns, whereas under traditional regulation, this would not have been the case.

**Q. ARE THERE ANY REAL-WORLD EXAMPLES OF HOW REVENUE
NEUTRALITY PROGRAMS CREATED SERIOUS PROBLEMS DURING AN
ECONOMIC CONTRACTION?**

A. Yes, one of the more widely-recognized failures of revenue decoupling occurred in Maine during the early 1990s. The program, known as "ERAM"

527 (“Electric Revenue Adjustment Mechanism”), was put into place for a three-year
528 trial period to encourage Central Maine Power (“CMP”) to promote DSM. The
529 ERAM had no adjustments for changes in regional activity. The adoption of the
530 ERAM coincided with a recession that resulted in lower sales levels and
531 substantial revenue deferrals. CMP was entitled to recover these deferrals under
532 the provisions of the ERAM mechanism, which by the end of 1992 reached \$52
533 million. Only a very small portion of this amount was attributed to CMP’s
534 conservation efforts as most of the deferral resulted from the economic
535 recession. The ERAM was viewed by many as a mechanism that shielded CMP
536 from the economic impact of the recession rather than furthering the intended
537 conservation incentives. CMP’s ERAM was terminated on November 30, 1993.¹

538 **Q. HOW IS COMMODITY PRICE RISK SHIFTED TO CUSTOMERS?**

539 A. When gas commodity prices increase, customers tend to reduce
540 consumption. In fact, it is likely that some portion of the decreases in use per
541 customer highlighted throughout the Company’s original application are the result
542 of price-induced reductions in consumption created by recent increases in natural
543 gas prices. Since the Company did not have DSM programs in place prior to
544 January 2007, these historic use per customer reductions are clearly based upon
545 actions taken by customers, not Questar. While the Company has been active in
546 developing and rolling out its DSM programs over the past year, it will take some
547 time before participation goals (savings) are realized. Thus, any balances

¹*Report on Utility Incentives Mechanisms for the Promotion of Energy Efficiency and System Reliability*, Maine Public Utilities Commission, Presented to the Utilities and Energy Committee, February 1, 2004, Internet Website:
http://www.maine.gov/mpuc/staying_informed/legislative/2004legislation/Eff-Rel%20Report-final.htm

(positive or negative) associated with the current CET are clearly not associated with DSM programs at this time.

Q. DO YOU AGREE WITH THE STATEMENT THAT REJECTING REVENUE NEUTRALITY IS COMPARABLE TO DENYING A UTILITY THE OPPORTUNITY TO EARN ITS ALLOWED REVENUES?

A. No. The fact that the utility exactly recovers its allowed revenues until its next rate case is not the problem. The issue is that a very large portion of the risk associated with recovering those revenues has been shifted entirely onto ratepayers without any corresponding benefit. If this proposal is, in fact, a good thing for the Company, then some type of benefit should be passed long to its customers for absorbing this risk. Further, the benefit needs to be more than just the DSM program offerings being provided by the Company. These programs and their potential benefits, while important, are limited. Even under the Company's best estimates, their DSM programs will only provide direct benefits to a small share of their residential and small commercial customer base while the CET impacts all GS-1 and GSS customers.

Q. HAVE ADJUSTMENTS TO A UTILITY'S ALLOWED RATE OF RETURN FROM REVENUE NEUTRALITY PROPOSALS BEEN RECOGNIZED IN OTHER UTILITY PROCEEDINGS?

A. Yes. CCS Exhibit 1.5 shows information from various past regulatory proceedings that have recognized cost of capital adjustments due to revenue neutrality programs that change the risk profiles of regulated utilities. Many of these adjustments have actually been proposed, or developed, by utilities.

571 These adjustments range from 25 to 100 basis points on a utility's allowed ROE.
572 To date, most of these adjustments have been offered in proposal form and, with
573 the limited exception of the FERC proceedings, have not been used to offset the
574 risk-shifting nature of the various revenue neutrality mechanisms. In fact,
575 revenue neutrality was rejected in most of the states where these risk-adjustment
576 proposals were offered. Recently, the Citizens Utilities Regulatory Board in
577 Kansas requested a 110 basis point reduction on the allowed ROE. This
578 proceeding recently settled and the revenue neutrality proposals were withdrawn
579 for later consideration in a generic docket. In Vermont, Green Mountain Power
580 agreed to a 50 basis point reduction and noted that its Alternative Regulation
581 Plan "has the effect of shifting risk associated with varying power costs to
582 ratepayers; in recognition of this risk shift, the Plan provides a lower return on
583 equity."²

584 **Q. DO YOU THINK THAT MAKING THESE ADJUSTMENTS WOULD BE**
585 **APPROPRIATE AT THIS TIME?**

586 A. No, for at least two reasons. First, any adjustments to the Company's
587 ROE should be done within the context of a rate case. In fact, over the past
588 several years, most revenue neutrality proposals (decoupling and SFV) have
589 been proposed within the context of a rate case allowing regulators to fully
590 evaluate all adjustment mechanisms that may, or may not, be needed to facilitate
591 energy efficiency. These potential adjustment mechanisms are not limited to

² Petition of Green Mountain Power Corporation for approval of an alternative-regulation plan, Docket No. 7175; Docket No. 7176, Vermont Public Service Board, December 22, 2006, Order Entered.

revenue decoupling or SFV alone, and can range from combinations of revenue neutrality and a utility's allowed ROE, to partial revenue decoupling, to simply changing test year billing determinants, to rate design changes, to no changes at all. As noted earlier, the current CET proceeding does not lend itself well to many of these types of adjustments since this is not a rate case where a broad range of other options would be candidates for consideration. Second, the adjustments provided in CCS Exhibit 1.5 are specific to the companies in those proceedings, and while these are important in providing insight into the range of potential ROE adjustments associated with revenue neutrality, any adjustment for Questar needs to be evaluated relative to its specific financial circumstances.

Q. IF NO ADJUSTMENTS ARE MADE TO OFFSET THE RISK-SHIFTING NATURE OF THE CET, CAN MAINTAINING THIS MECHANISM RESULT IN FAIR, JUST, AND REASONABLE RATES?

A. No. The Company's CET shifts a significant amount of risk to ratepayers. These risks include potential changes in price, the economy, and other factors like greater economy-wide energy efficiency. However, there is no corresponding offset in rates to compensate ratepayers for this shift. Granted, the current monthly balances associated with the CET have been mostly offsetting. But relatively low net-adjustments are more a function of current circumstances in the market as opposed to a removal of these risks. It could very well be the case that circumstances could shift (unfavorably) and change the overall nature of the balances accruing in the CET balancing account. Ratepayers would be on-call to cover those shortfalls should this negative market

realization materialize. Thus, maintaining the CET, while failing to recognize the risk-shifting inherent in this mechanism, results in rates that by definition are not fair, just, and reasonable and allows the utility to claw into the very monopoly profits that regulation is intended to control.

Q. DO YOU THINK THE FINANCIAL COMMUNITY RECOGNIZES THE RISK SHIFTING NATURE OF REVENUE NEUTRALITY MECHANISMS?

A. Yes, as well as a number of other favored, risk-shifting programs that can, depending upon the state, include the adoption of gas recovery clauses, weather normalization clauses, shorter weather normalization periods, and pass-through recovery of LAUF and uncollectibles expense. Revenue neutrality, in the form of revenue decoupling or SFV rate designs, however, appears to be the most popular regulatory mechanism with many of these financial analysts (with the exception of the few utilities that do not have GCRs). These analysts see revenue neutrality mechanisms as being beneficial to shareholders by reducing overall risk. Many financial analysts are starting to preference the ratings and categorizations of those companies that have such policies in place.

Q. DO YOU HAVE ANY EXAMPLES?

A. Yes, Moody's Investor Service ("Moody's"), in a June 2005 Special Comment on natural gas utilities, noted:

"Moody's believes that having utility rate designs that compensate the gas LDC for variations in conservation as with variations in weather would serve to stabilize the utility's credit metrics and credit ratings."³

³ *Special Comment: Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector*, Moody's Investors Services, June, 2005: 8.

Further, Moody's indicated that revenue decoupling can impact the business risk categorization under which utilities are judged by Standard and Poor's. This categorization, based upon business risk profiles, includes a measure for utilities that face supply and volumetric risk. Those with high risk are in the higher categories (highest risk category is 10), while those utilities that face lower risks by having adjustment clauses, are moved to lower levels. NW Natural, a gas distribution utility in Oregon that has both a GCR and decoupling mechanism, was able to lower its rank to 1, the lowest level category. Moody's recently reiterated the strong benefits revenue decoupling would provide in maintaining shareholder value. Such a mechanism will maintain strong credit metrics and improve credit ratings relative to utilities that do not have such mechanisms since revenue decoupling eliminates shareholder exposure to risk and volatility from price and climate changes.⁴

Q. CAN REVENUE DECOUPLING LEAD TO POTENTIAL COST INEFFICIENCIES?

A. Yes. Utilities, while regulated, are similar to other competitive firms in their goals of maximizing profits. These profits are a function of revenues and costs, both of which can reflect a certain degree of uncertainty. However, of the two, revenues can be more uncertain since, as noted earlier, they can be impacted by a wide range of factors beyond a utility's control like changes in commodity prices, changes in the economy, and changes in the weather, to name a few. Costs normally have more certainty and are typically within a utility's control.

⁴ *Special Comment: Local Gas Distribution Companies: Update on Revenue Decoupling and Implications for Credit Ratings*, Moody's Investor Services, June 2006.

Q. HOW DOES THE TRADITIONAL RATEMAKING PROCESS GIVE UTILITIES INCENTIVES TO REDUCE COSTS?

A. The regulatory lag inherent in the traditional ratemaking process gives utilities strong incentives to reduce costs, and potentially increase earnings, during periods between rate cases. In many instances, this will require effective efforts at reducing costs since, as noted earlier, revenues are much more uncertain. Active cost reducing efforts have the ability to compensate for unexpected changes (decreases) in revenues, thereby increasing profitability. However, under most revenue neutrality mechanisms, one-half of this equation, revenues is now known. Revenue decoupling eliminates revenue uncertainty (assuming a constant level of customers), which in turn can dampen efficiency incentives.

Q. GIVEN THE COMPANY'S RECENT FINANCIAL PERFORMANCE, IS THE CET NECESSARY?

A. No. From a financial perspective, maintaining the CET is unnecessary for at least 4 reasons:

- (1) The Company has been able to maintain relatively strong earnings despite decreases in use per customer.
- (2) The CET appears to have less to do with addressing revenue losses from energy efficiency than assuring revenue certainty. The order of magnitude of the potential losses resulting from DSM programs are small relative to the potential changes resulting from use per customer decreases.

(3) Revenue growth associated with adding new customers more than offsets revenue losses from both DSM and use per customer changes.

(4) As noted earlier in the Elcon White Paper opposing revenue decoupling, the real issue is profitability, not revenues. The real potential drag in overall Company profitability appears to have less to do with revenue losses and more to do with increases in incremental investment (rate base) per customer.

VI. DIRECT RATEPAYER BENEFITS OF THE CET ARE SMALL

Q. HOW SIGNIFICANT ARE THE COMPANY'S ANTICIPATED DSM SAVINGS?

A. CCS Exhibit 1.6 provides an overview of the anticipated level of natural gas savings (in Dth) from the Company's DSM programs over the three year pilot period. Total savings for each year increases from a level of 163,501 decatherms ("Dth") in the first year of the program to a high of 189,731 Dth by the third and last year of the pilot program. Two of these DSM programs account for 72 percent to 84 percent of the total anticipated DSM savings.

Q. HOW DO THESE COMPARE TO OVERALL SALES LEVELS?

A. The right hand side of the chart shows that these savings levels are very small shares of the Company's overall total sales. Using the Company's historic rate of sales growth (2.0 percent), shows that DSM savings over the next three years will only comprise between 0.184 percent to 0.205 percent of overall sales.

Q. HOW DO THESE SAVINGS PERCENTS COMPARE TO THE PROGRAMS LISTED BY OTHER LEADING GAS UTILITIES?

A. These levels of savings are low relative to most gas utilities that are often referred to as leaders in gas-use energy efficiency. CCS Exhibit 1.4, discussed earlier, shows that most of the leading gas utilities are achieving a level of savings that range from a low of 0.1 to a high of 1.0 percent. The average for the ten utility sample is a savings level of 0.5 percent.

Q. ARE YOU SUGGESTING THE COMPANY ISN'T DOING A GOOD JOB PROMOTING ITS DSM PROGRAMS?

A. Not at all. In fact, the Company has done a good job in developing and promoting its DSM plan to date. However, it appears from the savings estimates generated by Questar and its consultants that the cost-effective savings potential is less in Questar's service territory compared to other parts of the country for a variety of different reasons, many of which may have nothing to do with the Company's current efforts.

Q. WHAT ABOUT THE ANTICIPATED PARTICIPATION LEVELS?

A. CCS Exhibit 1.7 provides the anticipated participation for each of the Company's current DSM programs. As seen from the exhibit, most programs have participation rates that are far less than the majority of the customers in the GS-1 class. However, all residential and small commercial customers will be required to participate in the CET, to the benefit of the few that are participating in the Company's DSM programs. Again, this is not to suggest that the Company

is not doing a commendable job in promoting its DSM programs. It does suggest however, that the CET is too broadly applied.

Q. HOW LARGE ARE THE ANTICIPATED LOST REVENUES?

A. CCS Exhibit 1.8 provides the annual anticipated lost DNG revenues associated with the Company's DSM programs. These lost revenues, over a three-year period, range from a low of \$288,537 to a high of \$334,826. In each year, the amount of revenue lost from the promotion of cost-effective DSM is less than one-half of one percent of the Company's total GS-1 revenues.

Q. HAVE YOU ATTEMPTED TO ESTIMATE THE IMPACT THAT THE COMPANY'S DSM PROGRAMS WILL HAVE ON ITS FINANCIAL RESULTS?

A. Yes, CCS Exhibit 1.9 provides an analysis of the potential impact that the Company's current DSM programs may have on its financial results over the next three years. Overall, the Company could see a cumulative total revenue loss of some \$1.8 million associated with its DSM programs over the next three years. In addition, if recent trends continue, the Company could see a cumulative revenue loss of \$9.3 million decrease associated with a decrease in use per customer – an amount far in excess of the sales decreases resulting from its DSM programs. Over the same period, however, the Company could see a \$19.6 million cumulative increase in revenues due to customer growth. The net impact of these usages changes is \$5.2 million, resulting in a positive 1.61 percent impact on ROE. Thus, the Company may continue to see a net positive increase in its financial performance despite its promotion of DSM.

749 **Q. WHAT IF THE COMPANY'S DSM PROGRAMS PERFORM BETTER**
750 **THAN EXPECTED?**

751 A. The Company would have to attain DSM participation levels (or savings
752 per participant levels) well in excess of its current expectations in order for its
753 promotion of DSM to have a meaningful impact on its financial performance.
754 Currently, the Company expects to lose an estimated \$1.76 in lost revenues for
755 every one Dth in anticipated energy efficiency savings. The analysis in CCS
756 Exhibit 1.9 shows that at current expectations, the Company has \$5.2 million in a
757 positive earnings "buffer" that would have to erode before it became financially
758 challenged from promoting DSM. Given the lost revenue/DSM savings
759 relationship above, it would take an additional 3.0 million Dth in savings to bring
760 the Company to a point where DSM promotion stalls the growth in its achieved
761 ROE. This is a savings level that is some 160 percent higher than current cost-
762 effective savings expectations.

763 **Q. DO YOU THINK THIS LEVEL OF LOST REVENUES JUSTIFIES**
764 **MAINTAINING THE CET?**

765 A. No, the financial implications of promoting DSM appear to be small and it
766 would appear that a more important benefit the Company and its shareholders
767 get from the CET is associated with revenue insurance on potential changes in
768 use per customer and not the promotion of DSM. As I will discuss later in my
769 testimony, if the change in use per customer is the real concern, there are other,
770 more specific ratemaking tools to address this problem that are preferable to the
771 use of an overly-broad CET.

Q. WHAT IS THE RELATIONSHIP BETWEEN TOTAL USAGE, USE PER CUSTOMER, AND NET EARNINGS?

A. In the earlier phase of this proceeding, I provided an exhibit in my supplemental rebuttal testimony outlining the relationship between earnings and changes in sales and revenue. The relationship has been replicated in CCS Exhibit 1.10. This exhibit shows that changes in total usage are a function of: (1) the change in usage per customer associated with existing customers and (2) the new usage associated with customer growth. If usage increases resulting from customer growth outpace the usage decrease associated with reduced usage per customer (from existing customers), then total usage will increase. The inverse would occur if usage from customer growth was less than the total decreases created by reduced use per customer. If prices and costs are held constant, then earnings will continue to increase if new customer-related usage growth outpaces the decrease in use per customer for existing customers. The inverse would occur if new customer-created usage was less than the decreases in use per customer for existing customers; again, holding other factors constant. Thus, the impact that decreases in use per customer have on earnings growth can be offset for a utility serving a growing service territory. Utilities that serve very slow growing service territories could see earnings attrition if usage per customer falls. All of these relationships are based upon the premise that other factors are held constant.

Q. HAVE YOU UPDATED YOUR ESTIMATE OF THE CHANGES IN NET REVENUES FROM CHANGES IN USE PER CUSTOMER BASED ON THE COMPANY'S ACTUAL DATA?

A. Yes. I have presented a series of different exhibits that highlight some of these relationships from information included in the Company's Results of Operations. CCS Exhibit 1.11 shows the offsetting impacts on total usage created by (1) changes in use per customer and (2) changes associated with customer growth. Between 2001 and 2002, the Company saw a net GS1 sales decrease by 37,156 Dth. GS-1 customers during that period grew by 2.6 percent, or by some 17,976 customers. Usage decreases associated with decreases in use per customer were of a comparable percent (2.6 percent), or from 118.97 Dth/customer to 115.84 Dth/customer. As seen from the last three columns, the impact on total consumption was close to offsetting between the two impacts. Total usage reductions resulting from decreased use per customer were estimated to be around 2,119,521 Dth, while increased usage from new customers is estimated to be 2,082,365 Dth. The net change (subtracting the two) was a decrease of 37,156 Dth.

Q. HOW HAVE USAGE TRENDS CHANGED IN LATER YEARS?

A. There have been several years of both increases and decreases in total usage. Between 2002-2003, both use per customer and usage associated with new customers increased. Increases in annual use per customer is estimated to have contributed 2,126,113 Dth to overall sales. The increase in use from new customer growth was 3,401,338 Dth. The total annual change in sales that year

is the sum of these two impacts or 5,527,451 Dth. Other years have seen comparable movements; in the most recent full year, use per customer reductions contributed to a decrease of 1,148,163 Dth, while increased usage associated with customer growth was 2,094,399 Dth, resulting in a net positive change of 946,235 Dth. Over the past five years, there have been two years of net decreases in usage amounting to 878,484 Dth. There have also been three years of substantial net increases in usage accounting for 9,096,013 Dth. The net period change has been an increase in usage (net of decreases created by use per customer declines) of 8,217,528 Dth. In other words, the Company has seen total usage increase of over 8 million Dth despite the decrease in average use per customer.

Q. HAVE YOU UPDATED YOUR ANALYSIS TO EXAMINE THE CHANGES IN REVENUE ASSOCIATED WITH THESE USAGE CHANGES?

A. Yes, CCS Exhibit 1.12 presents a comparable analysis on a revenue basis. Two different columns have been provided that show the estimated changes in revenues associated with a decrease in use per customer versus the increase in revenues associated with changes in customer growth. Between 2001 and 2002, I have estimated that revenues decreased by \$2.8 million dollars due to decreased usage per customer. There was, however an estimated revenue increase due to customer growth for that period of \$4.9 million, resulting in a net revenue increase of \$2.1 million. In the subsequent year, it is estimated that revenues increased for both impacts since average usage per customer and

customer growth were both positive and significant (net positive change of \$17.8 million).

Q. HAVE YOU ATTEMPTED TO ESTIMATE THE FINANCIAL IMPACT OF THE RECENT CHANGES IN USAGE?

A. Yes. CCS Exhibit 1.13 provides that information. The exhibit consists of three pages: (1) a summary page; (2) detailed calculations on the estimated financial impact of changes in use per customer; and (3) detailed calculations on the estimated financial impact of changes from customer growth. The first summary page of the exhibit shows that for the better part of the five year period, the positive financial contributions of customer growth exceeded the negative implications of decreases in use per customer. The only exception was in 2003 when positive use per customer is estimated to have actually contributed more to the overall financial results than the increase in customer growth. The information at the bottom of the summary table provides comparable information for the return on equity ("ROE").

Q. IF USAGE PER CUSTOMER DOES NOT APPEAR TO BE DRAGGING DOWN THE COMPANY'S FINANCIAL PERFORMANCE, WHERE IS THE PROBLEM?

A. The problem appears to be associated with the cost of providing service to new customers. Page 1 of CCS Exhibit 1.13 shows that changes in rate base have the largest negative impact on the Company's achieved ROR – not changes in usage. CCS Exhibit 1.14 shows the Company's recent investment trends on an average and incremental basis. The bottom two rows are the more

informative. Average net utility plant in service per customer ranges between \$835 to \$934 per customer. However, the incremental net utility plant cost per change in customer is significantly higher at an average of around \$1,430 for the past several years.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS ANALYSIS?

A. It appears that the real challenge the Company faces is associated with its average incremental investment costs relative to the revenues gained from new customers. This has nothing to do with DSM, and appears to have less to do with decreasing use per customer (for existing customers), or usage in general. The problem appears to be one that is more cost-related and associated with making new capital investments. These are issues that are more appropriately addressed in the traditional ratemaking areas of cost recovery and rate design, rather than through a revenue decoupling mechanism like the CET. Trying to use decoupling as a means of correcting this problem is akin to creating an attrition adjustment. This would be inconsistent with the purpose of decoupling as it has been adopted in other states.

Q. DOES THIS DECOMPOSITION OF USAGE AND CUSTOMER GROWTH IMPACTS HAVE ANY BEARING ON THE CONSTRUCTION OF THE CET?

A. Yes. The common complaint that many LDCs express is that use per customer has been falling over recent years and that rates, set in the past, fail to catch up with the differences between test (or base) year use per customer and actual use per customer. In order to remedy this problem, decoupling has been proposed to “true-up” revenues to the test year in order to give LDCs the

884 opportunity to earn their authorized rate of return. In order to make an LDC
885 whole relative to the test year upon which its rates are based, a decoupling
886 mechanism should be examining the difference between actual and test year
887 revenues per customer relative to the test year customer level upon which costs
888 and revenues are based. However, the current formulation of the CET, like many
889 LDC decoupling proposals, adjust current period revenues for more than just
890 changes in use per customer from the test year, and also allows for revenue
891 recovery associated with customer growth.

892 **Q. CAN YOU PLEASE EXPLAIN THIS CONCERN IN GREATER DETAIL?**

893 A. Yes. The left hand side of CCS Exhibit 1.15 shows an example of the
894 Company's current CET methodology that is comprised of three important steps:

- 895 (1) determining the test year use per customer;
- 896 (2) estimating the difference between test (or base) year revenue per
897 customer and actual revenue per customer;
- 898 (3) Multiplying the difference by the actual (new) level of customers.

899 The third step in this calculation is the one to note since it allows for the collection
900 of revenues based upon customer growth.

901 **Q. HOW COULD THIS BE CHANGED TO BE MORE CONSISTENT WITH**
902 **THE TEST YEAR UPON WHICH RATES ARE SET?**

903 A. Instead of multiplying differences in actual from historic revenue per
904 customer by a new level of customers (step 3 discussed earlier), this difference
905 should instead be multiplied by the customers included in the base year. An
906 example of this calculation has been provided on the right hand side of CCS

Exhibit 1.15 and shows that the CET accrual account using this methodology would be approximately \$228,100 less than the current method of calculation for that given monthly example.

VII. ALTERNATIVE REMEDIES FOR DEALING WITH ENERGY EFFICIENCY DISINCENTIVES

Q. ARE THERE ANY OTHER POTENTIAL REGULATORY MECHANISMS FOR ADDRESSING DSM SALES LOSSES?

A. Yes. One of the more common regulatory mechanisms for dealing with sales losses associated with DSM implementation has been what is referred to as a lost revenue adjustment (“LRA”) mechanism. Under this approach, a utility’s ability to recovery lost revenues is based upon actual savings which result from its DSM programs. For instance, if a gas utility were promoting a Energy Star Clothes Washer program that achieved 8,700 Dth in savings, and had an average DNG rate of \$1.75, then the lost revenues associated with the program would be \$15,225. Thus, revenue recovery is restricted to specific DSM-created changes in sales and not some broader measure of sales loss (like decoupling) that could result from a variety of factors, many of which are beyond the utility’s control.

Q. HAVE MANY STATE COMMISSIONS UTILIZED AN LRA APPROACH?

A. Yes, several regulatory commissions have utilized an LRA approach to remove the purported disincentive associated with promoting DSM. LRAs were particularly common for electric DSM programs prior to the advent of retail competition and industry restructuring. While some states still technically allow

930 LRA recovery, there are few active proceedings where utilities continued to seek
931 recovery of these lost revenues.

932 **Q. IS AN LRA MECHANISM A POPULAR REGULATORY TOOL AMONG**
933 **ENERGY EFFICIENCY ADVOCATES?**

934 A. No. LRAs are typically opposed by energy efficiency advocates for at
935 least two reasons. First, most energy efficiency advocates believe that LRA
936 mechanisms are exceptionally difficult to implement in practice because
937 sophisticated measurement and estimation is required in order to determine
938 actual DSM savings, and as a result, DSM-related lost revenues. Second, most
939 energy efficiency advocates believe LRA mechanisms do not completely remove
940 the disincentive to promote DSM because the mechanisms are too narrowly
941 focused.

942 **Q. WHY WOULD AN LRA MECHANISM BE A MORE EFFECTIVE TOOL**
943 **FOR DEALING WITH DSM-CREATED REVENUE LOSSES THAN THE CET?**

944 A. There are various reasons that support the use of an LRA:

- 945 (1) Regulatory policy and industry trends are insisting upon greater
946 accountability in measuring energy efficiency savings and the
947 adoption of an LRA would be consistent with these movements;
- 948 (2) Revenue decoupling and the CET creates a disincentive for
949 accountability and energy efficiency measurement;
- 950 (3) An LRA would increase regulatory confidence in the use of DSM;

951 (4) The greater accountability created through an LRA could have
952 important planning implications which, in turn, could reduce overall
953 ratepayer costs.

954 **Q. HISTORICALLY, WHAT APPEARS TO BE THE BIGGEST REPORTED**
955 **DIFFICULTY ASSOCIATED WITH LRA MECHANISMS?**

956 A. Lost revenues are simply the product of average utility base rates and the
957 actual savings attained by the DSM program. Since the average utility base rate
958 is regulated and known, the fundamental challenge in estimating lost revenues is
959 measuring and verifying the actual amount of savings.

960 **Q. HOW ARE LOST REVENUES RELATED TO COST-EFFECTIVENESS?**

961 A. Lost revenues are fundamentally related to overall DSM program cost-
962 effectiveness in two ways. First, since lost revenues are a function of program
963 savings, and overall program savings determine whether a program is cost-
964 effective, lost revenues are clearly linked to cost effectiveness. Second, one of
965 the cost-effectiveness tests (Rate Impact Measure or RIM test) is based on lost
966 revenues. The RIM test, which measures the cost-effectiveness of a DSM
967 program from ratepayers or non-participants perspective, is calculated as the
968 difference between total program savings less total program costs including lost
969 revenues. Thus, lost revenues are integral components of any DSM cost-
970 effectiveness filing.

971 **Q. DOES THE RELATIONSHIP BETWEEN LOST REVENUES AND COST**
972 **EFFECTIVENESS HAVE ANY BEARING ON THE MEASUREMENT**
973 **CRITICISMS ASSOCIATED WITH LRA MECHANISMS?**

A. Yes. The argument that lost revenues are difficult to measure is somewhat incompatible with cost-effectiveness findings upon which DSM program approvals are usually based. The implication is that regulatory approval of proposed DSM programs cannot really be based upon any accurate level of savings leaving a potentially large amount of unsupportable costs to be recovered in rates. Allowing a large share of unsupported DSM costs into rates would be no different than allowing a similar share of unsupported costs into rates for any other type of resource like a transmission line, power plant, or O&M expense. Allowing unsupportable costs into rates cannot result in rates being fair, just and reasonable.

Q. WHY DO YOU THINK MANY OF THESE LRA MEASUREMENTS ISSUES ARE LESS RELEVANT TODAY THAN IN THE PAST?

A. They are less relevant for a variety of reasons:

- (1) Measurability challenges were promoted well over a decade ago and the nature of the energy services business has changed significantly to include a higher level of monitoring and verification ("M&V") of DSM savings.
- (2) The regulatory standards and requirements associated with M&V are becoming more stringent for accountability reasons.
- (3) Broader industry and public policy issues are driving M&V to higher standards and this will continue to be the case as DSM is being considered as a resource to meet utility planning requirements and

996 air emissions standards that are likely to be adopted in response to
997 global climate change issues.

998 **Q. REGARDING YOUR FIRST POINT, WHAT CHANGES IN THE ENERGY**
999 **SERVICES INDUSTRY HAVE ANY BEARING ON THE LOST REVENUE**
1000 **MEASUREMENT ISSUE?**

1001 A. There have been a number of changes in the energy services business
1002 that have had a positive impact on measurement issues including:

1003 (1) Greater reliance on performance-based terms and conditions in
1004 energy service contracts;

1005 (2) Greater degrees of competition requiring service differentiation via
1006 performance and deliverability;

1007 (3) Better measurement equipment and software;

1008 (4) Greater experience with measurement techniques;

1009 (5) Specialization with some energy service companies focusing on
1010 independent M&V services; and

1011 (6) Expanding industry estimated to have over \$2 billion in project
1012 investment.

1013 **Q. HAVE REGULATORY STANDARDS CHANGED TO ADDRESS THESE**
1014 **MEASUREMENT ISSUES?**

1015 A. Yes, regulatory standards have changed in at least two ways. First, there
1016 has been greater understanding and appreciation for M&V for those utilities
1017 requesting cost recovery. Second, as will be discussed later in my testimony,

1018 many states have moved to third party administrators which in many instances
1019 require M&V to assess the effectiveness of publicly-supported programs.

1020 **Q. ARE THERE CHANGES IN INDUSTRY AND PUBLIC POLICY THAT**
1021 **TEND TO INCREASE M&V REQUIREMENTS?**

1022 A. There are at least two important changes in industry and public policy that
1023 are quickly increasing M&V requirements and standards. Currently, most of
1024 these changes are associated with electric DSM, but will likely have important
1025 implications for gas DSM as well. The first change has to do with the use of
1026 DSM as a resource for planning purposes and the second change is the use of
1027 DSM as a resource in clean air market models being driven by rapidly escalating
1028 climate change concerns among policy makers.

1029 **Q. HOW DO UTILITY PLANNING ISSUES AFFECT M&V?**

1030 A. Many electric utilities, and even regional transmission organizations
1031 ("RTOs") have historically had a difficult time accepting DSM resources for
1032 system planning purposes. At best these resources were heavily discounted.
1033 However, the challenges of building or acquiring new baseload resources have
1034 become more substantial due to climate change concerns, fuel price volatility and
1035 concerns relating to storing spent nuclear fuel. This leaves very little in the way
1036 of additional resource options with the exception of renewables and DSM. If
1037 DSM is to be used, continued efforts in M&V are going to have to occur in order
1038 to bridge the gap of confidence between regulators pushing DSM as a resource,
1039 and utility planners reluctant to use DSM for planning purposes.

1040 **Q. HOW ARE CLIMATE CHANGES AND CLEAN AIR MARKETS DRIVING**
1041 **M&V FOR DSM?**

1042 A. Since the passage of the Clean Air Act Amendments of 1990, clean air
1043 markets, implemented through what is referred to as “cap and trade” programs
1044 have been the policy of choice for reducing air emissions. This has clearly been
1045 the case for SO₂ and NO_x, and will likely occur for future carbon regulation.
1046 Many states are already in the process of attempting to use DSM as a potential
1047 offset for carbon emissions. Moreover, several states and regions are
1048 considering mandatory DSM portfolio requirements much like renewable energy
1049 portfolio standards (“RPS”). DSM savings under such a program would likely
1050 have environmental attributes with tradable credits. Air market regulators,
1051 however, are very strict in ensuring that any resource upon which a tradable
1052 environmental attribute is based must be measurable and verifiable. This will put
1053 increasing pressure on M&V for utility DSM. If air market regulators can rely
1054 upon these DSM savings estimates for their environmental attributes, then it
1055 would seem reasonable that utility regulators could use them as a basis for lost
1056 revenue recovery as well.

1057 **Q. ARE THERE ANY CAVEATS IN YOUR DISCUSSION ABOUT LOST**
1058 **REVENUE MEASUREMENT ISSUES?**

1059 A. Yes, this discussion assumes a certain degree of regulatory oversight and
1060 accountability. Thus, the issue is not the degree to which DSM savings can be
1061 measured as much as it to what extent the regulatory oversight process requires
1062 that they be measured, and the methods by which M&V is governed. This is one

1063 the primary reasons why my prior testimony in this proceeding emphasized the
1064 role of M&V and stressed clearly defining this M&V process prior to the adoption
1065 of the CET.

1066 **Q. DO YOU THINK REVENUE DECOUPLING LIKE THE CET CREATES**
1067 **NEGATIVE INCENTIVES FOR M&V?**

1068 A. Yes. If revenue decoupling removes a utility's incentive to make sales, it is
1069 more than likely to also remove a utility's incentive to closely monitor sales
1070 losses. Under the CET, sales losses, for whatever reason, are now of no
1071 consequence to a utility.

1072 **Q. HOW DOES THE ACCOUNTABILITY ASSOCIATED WITH LOST**
1073 **REVENUES ENHANCE COMMISSION CONFIDENCE IN DSM?**

1074 A. An LRA directly ties a utility's incentive to DSM by tying lost revenue
1075 recovery to actual performance. As such, an LRA can be thought of as a type of
1076 performance-based regulation since it is the utility's performance that defines its
1077 ability to recover revenues associated with DSM-created sales losses. Tying a
1078 utility's incentive to accurate measurement gives the Commission, and other
1079 stakeholders, increased confidence that (1) the revenues being recovered by
1080 utilities are based upon verifiable achieved savings and (2) the costs incurred for
1081 DSM program development and implementation are tied to verifiable savings,
1082 thereby justifying ratepayers' investment in these programs.

1083 **Q. CAN THIS GREATER ACCOUNTABILITY HAVE IMPORTANT**
1084 **IMPLICATIONS FOR RESOURCE PLANNING AND FUTURE RATEPAYER**
1085 **COSTS?**

1086 A. Yes since greater accountability reduces the discount to DSM as a
1087 planning resource. Greater accountability can have direct implications for
1088 ratepayer costs if it defers investment made from discounted DSM benefits.
1089 Consider as an example, a planning process that discounts DSM savings over
1090 some fixed period of time by 50 percent. Now take that same DSM program and
1091 apply a much higher degree of M&V upon its achieved savings, that reduces the
1092 overall benefit discount to 25 percent of total annual program savings. This 25
1093 percent differential represents a real capital investment that would otherwise
1094 have to be developed to meet ratepayer demand requirements that has now
1095 been either eliminated or deferred.

1096 **Q. IS AN LRA THE ONLY MECHANISM BY WHICH NEGATIVE DSM**
1097 **INCENTIVES CAN BE REMOVED FROM A UTILITY?**

1098 A. No. One alternative method being utilized by several states has been the
1099 use of a third-party administrator for the promotion and development of energy
1100 efficiency programs. These third-party administrators are independent bodies,
1101 usually housed within a state agency, and not directly associated with any
1102 specific utility company, although utilities may provide input, or serve on boards
1103 advising these administrators. While the responsibilities of these administrators
1104 can vary by state, they are usually in charge of developing, monitoring and
1105 verifying the success of DSM programs, market transformation initiatives, and in
1106 many instances, clean energy programs.

1107 **Q. WHAT ARE THE PERCEIVED BENEFITS OF THESE THIRD PARTY**
1108 **ADMINISTRATORS?**

1109 A. One of the primary benefits is having a dedicated administrator with no
1110 potential conflicts or disincentives to promote energy efficiency and clean energy
1111 technologies. There can also be the additional benefit of pooling resources,
1112 which could potentially reduce the overall cost of delivering DSM and clean
1113 energy. Having these types of activities centralized into one public agency can
1114 also reduce coordinating costs and potential redundancies across different types
1115 of electric and gas utility programs.

1116 **Q. HOW MANY STATES CURRENTLY HAVE SUCH THIRD PARTY**
1117 **ADMINISTRATORS?**

1118 A. CCS Exhibit 1.16 provides an overview of the states which currently utilize
1119 a third-party administrator for the development and promotion of DSM programs.
1120 Most of these administrators oversee both electric and natural gas efficiency
1121 programs. Several, like New Jersey, also oversee clean energy rebate programs
1122 for things like the development of solar energy as required under the state's
1123 Renewable Portfolio Standard ("RPS"). Most of these programs are funded by
1124 some type of state-wide surcharge.

1125 **VIII. ALTERNATIVE METHODS FOR DEALING WITH DECLINING USE PER**
1126 **CUSTOMER**

1127 **Q. ARE THERE ANY METHODS THAT COULD BE UTILIZED TO**
1128 **CORRECT OR ADJUST FOR USE PER CUSTOMER-RELATED CHANGES IN**
1129 **SALES?**

1130 A. Yes. There are a number of examples where the traditional regulatory
1131 ratemaking framework has reflected changes in usage resulting from exogenous

factors like rate changes and even DSM program savings. The typical mechanisms for making these adjustments have been within the context of modifications to the test year usage levels upon which a specific rate case is based. There are several examples of test-year modifications on both a historic and forecasted basis.

Q. CAN YOU PLEASE EXPLAIN THE PURPOSE OF A TEST YEAR IN THE RATEMAKING PROCESS?

A. A test year defines a set period of time, reflecting typical utility operations, upon which regulated utility rates are based. A test year can be based upon a historic period of time using historic information, adjusted for what are commonly referred to as “known and measurable changes” to revenues, expenses, and rate base. Alternatively, a test year can be based upon some future period of time provided revenues, expenses, and rate base projections are developed and adjusted in a fashion that reasonably reflects expected future utility operations.

Q. HOW WOULD A HISTORIC TEST YEAR REFLECT CHANGES IN NATURAL GAS USAGE?

A. A strict definition of a historic test year would only reflect changes in natural gas usage at that point in time. However, a test year which is allowed to reflect known and measurable changes could clearly accommodate reduced sales from DSM and could also reflect structural changes in gas use resulting from shifts in use per customer trends. For instance, it has not been uncommon in past ratemaking proceedings to estimate the potential repression or stimulation that could result from a particular rate design change. Given recent changes in

residential natural gas use, a regression estimate could be used to adjust test year billing determinants to reflect overall changes in use per customer.

Q. PRACTICALLY, HOW WOULD THIS REGRESSION ADJUSTMENT WORK?

A. The most straightforward way to make a use per customer regression adjustment would be to average the overall changes in use per customer over some fixed period of time to develop an overall adjustment factor to apply to the estimated usage levels relied on to develop rates. The challenge in developing this factor would be in determining the overall period upon which the factor would be based and any adjustments that might be needed to correct for any near-term usage trends. For instance, as I noted in my supplemental rebuttal testimony earlier in this docket, the decrease in use per customer appears to have slowed in recent years relative to historical trends. Basing an adjustment factor over a longer run use per customer trend could, therefore, overshoot the near term changes anticipated in the market.

Q. PLEASE PROVIDE AN EXAMPLE?

A. CCS Exhibit 1.17 provides an example of how a use per customer regression adjustment could be made as a known and measurable change within the context of a historic test year. Two panels are provided to the right and left of this exhibit reflecting regression adjustments based upon a three-year average and five-year average change in use per customers, respectively. While the exhibit uses Questar-specific data, both examples are presented as illustrative in nature. Row 1 in both examples lists the absolute decrease in use per customer

in the two different periods examined. The repression adjustment to test year revenues is provided on row 11 and reflects the additional amount that would need to be collected in rates if changing trends in use per customer were included in a historic test year.

Q. HOW WOULD THIS ADJUSTMENT CHANGE FOR A FORECASTED TEST YEAR?

A. Correcting for changes in use per customer on a forecasted test year basis is relatively straightforward. By definition, a forecasted test year is based upon estimated revenues and costs for some future period. Revenues and ultimately sales are typically based upon projections developed in a load forecast which should be similar, if not the same, as the one included in the Company's Integrated Resource Plan ("IRP"). Over the past several years, for instance, Questar's IRP has reflected longer-term trends in changes in use per customer upon which their planning process is based.

Q. COULD USAGE-RELATED CHANGES RESULTING FROM DSM ALSO BE INCLUDED IN THE FORECASTED TEST YEAR?

A. Yes, provided (1) there is no separate lost revenue recovery mechanism and the forecast is the only place where DSM-created usage changes are accounted for or (2) that any periodic lost revenue process is treated as a true up to what is included in the test year billing determinants. A DSM adjustment would be relatively straightforward calculation. First, total usage would be forecasted for several years including the test year being used to set rates. As noted earlier, this forecast, if conducted appropriately, would account for changes

1201 in use per customer. Second, forecasted usage levels would be reduced for the
1202 anticipated savings associated with DSM programs for the years those savings
1203 are anticipated to be available.

1204 **Q. WHAT ARE SOME OF THE BENEFITS OF USING A FORECASTED**
1205 **TEST YEAR TO MAKE THESE TYPES OF CORRECTIONS?**

1206 A. There are at least three potential benefits. First, the use of a forecasted
1207 test year to make usage-related adjustments to rates would be based upon
1208 forward looking information that would better track anticipated trends in the near
1209 term. Second, a forecasted test year could, and probably should, be based upon
1210 the same forecasted usage information that the Company is using for its own
1211 system planning purposes. Third, and most importantly, the current risk
1212 associated with changes in sales would remain with the Company and its
1213 shareholders, and not shifted to ratepayers. Using a forecasted test year to
1214 adjust for changes in usage, particularly changes in use per customer, would be
1215 a far preferable alternative than continued use of the CET.

1216 **IX. CONCLUSIONS AND RECOMMENDATIONS**

1217 **Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS IN THIS**
1218 **PROCEEDING?**

1219 A. I have three primary recommendations:

1220 (1) The Commission should discontinue the use of the CET since it
1221 shifts considerable sales risk to ratepayers with little to no offsetting
1222 benefits for ratepayers assuming those risks. Further, the CET is
1223 overly broad in addressing the problems associated with declining

1224 use per customer trends and is unnecessary to address incentive
1225 issues associated with the promotion of DSM programs.

1226 (2) The Commission should adopt a lost revenue adjustment (“LRA”)
1227 mechanism to make the Company whole for changes in usage
1228 resulting from its DSM programs. Lost revenue recovery should be
1229 tied directly to the estimates included in the Company’s DSM cost-
1230 effectiveness filings, and updated according to the ongoing
1231 monitoring and verification (M&V) process.

1232 (3) The Commission should direct the Company to address any
1233 financial challenges created by decreases in use per customer in its
1234 next rate case through the use of a forecasted test year or some
1235 known and measurable adjustment if a historic test year is utilized
1236 for ratemaking purposes.

1237 **Q. DO YOU HAVE ALTERNATIVE RECOMMENDATIONS?**

1238 A. Yes, should the Commission reject my primary recommendations and
1239 decide to maintain the CET I would recommend:

1240 (1) The Commission require the CET to be modified such that
1241 decoupling true-ups are based upon the difference in historic and
1242 actual use per customer times test year customers (or base year
1243 customers upon which the revenue per customer statistic is
1244 derived) rather than actual customers.

1245 (2) The Commission should explicitly recognize the risk shifting nature
1246 of the CET and indicate in its Order that this shifting of risk will be
1247 considered in setting the Company's ROE in its next rate case.

1248 **Q. DOES THIS CONCLUDE YOUR TESTIMONY FILED ON JUNE 1, 2007?**

1249 **A Yes.**